UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

March 2, 2001

MEMORANDUM TO: Michael R. Johnson, Chief
Performance Assessment Section
Inspection Program Branch
Division of inspection Program Management
Office of Nuclear Reactor Regulation

FROM: August K. Spector, Communication Task Lead
Inspection Program Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

August K. Spector

SUBJECT: REACTOR OVERSIGHT PROCESS SUMMARY OF PUBLIC MEETING HELD ON MARCH 1 THROUGH 2, 2001

From March 1 through 2, 2001 a public meeting was held at the NRC Headquarters, Two White Flint North, Rockville, MD to discuss and review the initial implementation of the revised reactor oversight process. An agenda, attendance list, and information exchanged at the meeting are attached.

Attachments:

1. List of Participants
2. Agenda
3. Summary of results from meeting with NEI/Industry February 22, 2001
4. Cross-cutting Issues Background
5. Unit Shutdowns and Power Reductions per 7,000 critical hours
6. Insert for NEI-99-02, Reactor Core Isolation Cooling System
7. Safety System Functional Failures recommended change comments
8. Letter from Stephen Floyd regarding topics for public lessons learned meeting
9. ROP Lessons Learned Statement of Issues related to Unavailability Performance Indicator
10. Frequently Asked Questions, Log. 11, 15, 16, 17

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NRC Public Meeting
Reactor Oversight Process
List of Participants
March 1 and 2, 2001

S. Ferrel, TVA
D. Hickman, NRC.
A. Madison, NRC
M. Johnson, NRC
A. Spector, NRC
T. Boyce, NRC
S. Morris, NRC
D. Raleigh, Scientech
D.M. Olsen, Dominion
R. Ritzman, PSEG
M. Taylor, Exelon
S. Floyd, NEI
Wade Warren, SNC
M. Rubin, NRC
F. Gillespie, NRC
B. Brady, NRC
J. Nagle, PSEG
G. Solamon, PSEG
J. Caves, CPL
J.W. Chase, OPPD
P. Loftus, COMED
D.R. Robinson, Nebraska Public Power
J. Butler, NEI
C. See, NRC
William Dean, NRC
A.D. El-Bassioni, NRC

Attachment 1

NRC Public Meeting
Reactor Oversight Process
Agenda
March 1 and 2, 2001

1. Discussion of Initiating Event Performance Indicator pilot activity.
2. Discussion of Pilot Testing Replacement for Unplanned Power Changes performance indicator
3. Discussion of removal of t/2 for surveillance failure in Unavailability Performance I Indicator
4. Discussion of reporting Reactor Core Insolation Cooling (RICI) system in the Safety System Functional Failure performance indicator.
5. Discussion of Electronic Information Exchange (EIE) pilot activity.
6. Discussion and update on industry trends
7. Discussion of coordination of reporting requirements

8. Discussion of key issues for consideration at the public NRC Lessons Learned Workshop
9. Review and approval of Frequently Ask Questions.

Attachment 2

SUMMARY OF RESULTS FROM
MEETING WITH NEI/INDUSTRY
FEBRUARY 22, 2001

1. What unavailable hours should be counted in the SSU?

   a. Should all unavailable hours of a train be counted whenever the <u>function</u> is required, or only when the <u>train</u> is required?

   Both NRC and NEI agreed that unavailable hours during power operation and shutdown should be counted separately. They would then be add together to calculate one overall unavailability number. (The NRC wants shutdown unavailability to eventually become a separate PI, but for now they would be included together.) NRC and NEI agree that, during power operation, unavailable hours would be counted any time a train is taken out of service for any reason when it is required to be in service by the Technical Specifications (T.S.). During shutdown, NEI proposed to count the "primary and first backup equipment for performing a safety function credited in the shutdown management plan." The NRC proposed to count unavailable hours for any train of a system whose function is required. While the NRC proposal would count <u>all</u> trains in systems with more than two trains and the NEI proposal would not, the NEI proposal seems to be acceptable and proper. However, we need to ensure that we are counting two trains of the <u>same system</u> (as opposed to HPCI and one train each of ADS and LPCI or core spray), and

   b. Should on-line maintenance be excluded from the SSU if the licensee has a risk analysis that show that the increase in risk is small?

   Both NRC and NEI agree that on-line maintenance (and off-line maintenance whenever the system function is required by T.S.) should be counted.

   c. Should support system unavailable hours be counted as monitored system unavailable hours?

   The NRC and NEI agree that, as long as support systems are not monitored in the SSU, support system unavailable hours should be cascaded to the monitored systems. (A corollary to this is that support systems be counted as available if they have any train available, i.e., support systems are not required to be single failure proof.)

   d. Should unavailable hours due to design deficiencies be excluded from the SSU PI?

   Both NRC and NEI agree that long-standing design deficiencies should not be included in the SSU. We are considering including design deficiencies that occur within the 12 month period of the current calculation.

2. How should demand and run failures should be handled in the SSU.?

Attachment 3

Due to personnel illnesses and training, the NRC work on this item was incomplete at the time of the meeting. NEI proposed that, in situations where the time of occurrence of a failure is indeterminate, unavailable hours be counted only from the time of discovery and a demand failure be assumed and evaluated through the Significance Determination Process (NEI did not distinguish between demand failures and discovered conditions). This item is still open.

3. What credit for operator action is appropriate in the SSU.?

    a. Should the SSU allow credit for operator actions that are virtually certain to be successful?

    b. Should credit allowed for more complicated recovery actions?

    c. If credit for more complicated recovery actions is allowed what conditions should be applied to such actions?

    Both NRC and NEI agree that the current allowances for operator recovery action should be retained with no changes or additions, but that plant-specific exceptions could be made for special circumstances.

4. Should default values for hours a train is required be allowed?

    NEI proposes to allow the use of default values for the hours a train is required because of the burden on licensees to collect the actual data. The NRC has data that show the calculated SSU value can be significantly lower in certain situations when the default hours are used. The NRC will look at the possibility of providing guidelines for licensees on when the use of default h ours is acceptable and when it is not.

ISSUE BACKGROUND

Cross Cutting Issues - No Color Findings.

These are issues related to human performance, problem identification, or safety-conscious environment, which have the potential for affecting more than one cornerstone.

The NRC identified the following two non-color findings at a recent exit meeting.

Problem Identification and Resolution (PIR)

a. Green finding Non-Cited Violation was issued due to compromising the ability of the Auxiliary Building Ventilation to perform its safety function due to a fire damper failing in the close position. The cause of the failure was a lose locking wing-nut in the damper position linkage. The NRC also identified previous Notifications associated with
   1. The loosening of the wing-nuts in the ABV dampers in July 99
   2. The functionality/operability of the damper indication panels in the control room.

b. A green finding Non-Cited Violation was issued because of the temporary loss of decay heat removal when the outlet temperature control valve in one of the CCW heat exchanger failed, while the redundant heat exchanger was lined-up to support pump testing The NRC had also identified previous notifications associated with the excessive pipe vibration in the CCW HX area.

Human Factors/Performance

a. A spring was replaced in an auxiliary building ventilation damper was replaced with a modified spring (cut) under a corrective maintenance work order rather than a DCP.
b. The CCW pump impeller was under-filed under re-install under a corrective maintenance activity rather than a DCP.

ISSUE #1

0610* Section 06.02 provides guidance for issues related to Cross Cutting areas. Specifically section b provides guidance into what constitutes "Multiple Failures" and also provides an example of what should be documented as a non-color finding. The example provided contains 4 distinct events going back nine months.

Attachment 4

Are two events, as noted above, sufficient to establish an adverse performance trend and documented as non-color findings?

ISSUE #2

The example contained in 0610* Section 06.02.b "Multiple Failures," appears to go back nine months back in time in establishing prior events that will be aggregated to establish a trend.

Is there a time when events may be too "young" to be counted because corrective actions may not have been fully implemented and not enough time has passed to assess their effectiveness?

ISSUE #3

0610* Appendix B Section D " Extenuating Circumstances (Group 3 questions) number (5) asks the inspectors whether the issue describe a substantive cross-cutting issue which has been captured in a number of individual findings in the current or previous reports (same as 'multiple')......

What does a number mean? In the example in Section B 0610* does not provide any further guidance as to what a number is.

ISSUE #4

0610* is also (appears to be) silent on what is an appropriate time to complete a corrective and/or to determine effectiveness before it becomes untimely or ineffective in the eyes of the inspector. Corrective actions taken, iaw GL 91-18, are commensurate with the safety significance of the event, therefore, corrective actions that may require placing the plant in an abnormal configuration to correct a problem of low safety significance event, may be delayed until a refueling outage. However if the condition repeats itself during that period, does it mean that we have an untimely or ineffective corrective action program?

Is there more concrete guidance as to when corrective actions need to be completed for low significant events before they become untimely?

DRAFT

UNIT SHUTDOWNS AND POWER REDUCTIONS PER 7,000 CRITICAL HOURS

Purpose
This indicator monitors the number of unit shutdowns and reductions in average daily power level of greater than 20 percent of full power. It may provide leading indication of risk-significant events but is not itself risk-significant. The indicator is calculated per 7,000 critical hours to monitor the number of plant power changes for a typical year of operation.

Indicator Definition
The number of unit shutdowns and reductions in average daily power level of greater than 20 percent of full power during the previous four quarters per 7,000 critical hours.

Data Reporting Elements
The following data are reported for each reactor unit:

- the number of unit shutdowns and reductions in average daily power level of greater than 20 percent of full power in the previous quarter
- the number of critical hours in the previous quarter

Calculation
The indicator is determined using the values for the previous four quarters as follows:

$$\text{value} = \frac{\text{(number of unit shutdowns and power reductions in the previous 4 qtrs)}}{\text{(number of critical hours in the previous 4 qtrs)}} \times 7{,}000 \text{ hrs}$$

Definition of Terms
Average Daily Power Level is the net electrical energy generated during the day (measured from 0001 to 2400 hours inclusive) in megawatt-hours, divided by 24 hours.

Net electrical energy generated is the gross electrical output of the unit measured at the output terminals of the turbine-generator during the reporting period, minus the normal station service electrical energy utilization. If this quantity is less than zero, a negative number should be used.

Clarifying Notes
7,000 hours is used because it represents one year of reactor operation at about an 80% availability factor.

2,400 critical hours is the minimum number of critical hours in four consecutive quarters for which an indicator value is calculated. Rate indicators can produce misleadingly high values when the denominator is small; for critical hours under 2,400, a single shutdown can produce a value that crosses the green-white threshold. Therefore, the displayed value will be N/A. All data elements must nevertheless be reported.

Attachment 5

Unit shutdowns and power reductions that are not counted are (1) those that are scheduled prior to startup from a refueling outage (i.e., mid-cycle maintenance outages and the next refueling outage); (2) those that are directed by the load dispatcher under normal operating conditions due to load demand and economic reasons, or for grid stability or nuclear plant safety concerns arising from external events outside the control of the nuclear unit; (3) anticipatory unit shutdowns or power reductions due to external events, such as hurricanes, tornadoes, or range fires, that threaten the safety of the nuclear unit or its transmission lines; (4) certain proceduralized unit shutdowns or power reductions in response to expected problems, such as accumulation of marine debris or biological contaminants in certain seasons (each situation is different and should be identified to the NRC for a determination as to whether it should be counted); and (5) those that are included in the unplanned scram indicator.

Unit shutdowns and power reductions that are counted are all those not excluded by the above paragraph.

INSERT FOR NEI 99-02, PAGE 82, LINE 22:

Reactor Core Isolation Cooling system: For BWRs that have taken credit for the RCIC system in mitigating a rod drop accident, RCIC failures are reportable per 10 CFR 50.73(a)(2)(v) and are included in this indicator. For plants that have not taken credit for the RCIC system in mitigating a rod drop accident, RCIC failures are not reportable per 10 CFR 50.73(a)(2)(v). (The question of RCIC reportability for these plants is currently under review by the NRC.) However, because RCIC has safety significance, and to provide consistency in the ROP among licensees, failures of RCIC at all BWRs with the RCIC system are included in this indicator. For plants that do not take credit for RCIC in an accident analysis, any failure of RCIC to meet its design basis requirements that would prevent the system from providing flow to the reactor vessel at the design flow rate would be counted in this indicator.

Attachment 6

Clarifying Notes

The definition of SSFFs is identical to the wording of the current revision to 10 CFR 50.73(a)(2)(v). Because of overlap among various reporting requirements in 10 CFR 50.73, some events or conditions that result in safety system functional failures may be properly reported in accordance with other paragraphs of 10 CFR 50.73, particularly paragraphs (a)(2)(i), (a)(2)(ii), and (a)(2)(vii). An event or condition that meets the requirements for reporting under another paragraph of 10 CFR 50.73 should be evaluated to determine if it also prevented the fulfillment of a safety function. Should this be the case, the requirements of paragraph (a)(2)(v) are also met and the event or condition should be included in the quarterly performance indicator report as an SSFF. The level of judgement for reporting an event or condition under paragraph (a)(2)(v) as an SSFF is a reasonable expectation of preventing the fulfillment of a safety function.

In the past, LERs may not have explicitly identified whether an event or condition was reportable under 10 CFR 50.73(a)(2)(v) (i.e., all pertinent boxes may not have been checked). It is important to ensure that the applicability of 10 CFR 50.73(a)(2)(v) has been explicitly considered for each LER considered for this performance indicator.

NUREG-1022: Unless otherwise specified in this guideline, guidance contained in the latest revision to NUREG-1022, "Event Reporting Guidelines, 10CFR 50.72 and 50.73," that is applicable to reporting under 10 CFR 50.73(a)(2)(v), should be used to assess reportability for this performance indicator.

Planned Evolution for maintenance or surveillance testing: NUREG-1022, Revision ~~1~~ 2, page 56 ~~70~~ states, "The following types of events or conditions generally are not reportable under these criteria:...Removal of a system or part of a system from service as part of a planned evolution for maintenance or surveillance testing..."

The word "planned" is defined as follows:

> "Planned" means the activity is undertaken voluntarily, at the licensee's discretion, and is not required to restore operability or for continued plant operation.

A single event or condition that affects several systems: counts as only one failure.

Multiple occurrences of a system failure: the number of failures to be counted depends upon whether the system was declared operable between occurrences. If the licensee knew that the problem existed, tried to correct it, and considered the system to be operable, but the system was subsequently found to have been inoperable the entire time, multiple failures will be counted whether or not they are reported in the same LER. But if the licensee knew that a potential problem existed and declared the system inoperable, subsequent failures of the system for the same problem would not be counted as long as the system was not declared operable in the interim. Similarly, in situations where the licensee did not realize that a problem existed (and thus could not have intentionally declared the system inoperable or corrected the problem), only one failure is counted.

Additional failures: a failure leading to an evaluation in which additional failures are found is only counted as one failure; new problems found during the evaluation are not counted, even if

SAFETY SYSTEM FUNCTIONAL FAILURES

Purpose

This indicator monitors events or conditions that ~~alone~~ prevented, or could have prevented, the fulfillment of the safety function of structures or systems, or the total loss of the RCIC decay heat removal function that are needed to:

(a) Shut down the reactor and maintain it in a safe shutdown condition;
(b) Remove residual heat;
(c) Control the release of radioactive material; or
(d) Mitigate the consequences of an accident.

Indicator Definition

The number of events or conditions that ~~alone~~ prevented, or could have prevented, the fulfillment of the safety function of structures or systems, or the total loss of the RCIC decay heat removal function in the previous four quarters.

Data Reporting Elements

The following data is reported for each reactor unit:

- the number of safety system functional failures during the previous quarter
- the number of reactor core isolation cooling (RCIC) functional failures during the previous quarter

Calculation

unit value = number of safety system functional failures and RCIC functional failures in the previous four quarters

Definition of Terms

Safety System Function Failure (SSFF) is any event or condition that prevented, or~~alone~~ could have prevented the fulfillment of the safety function of structures or systems that are needed to:

(A) Shut down the reactor and maintain it in a safe shutdown condition;
(B) Remove residual heat;
(C) Control the release of radioactive material; or
(D) Mitigate the consequences of an accident.

RCIC functional failure is any event or condition that prevented, or could have prevented the fulfillment of its decay heat removal function independent of RCIC reporting requirements specified in 10 CFR 50.72 and 73 and guidance provided in

Attachment 7

NUREG-1022 Revision 2. The RCIC function monitored for this performance indicator is the ability of the RCIC system to cool the reactor vessel core and provide makeup water into the reactor vessel.

The indicator includes a wide variety of events or conditions, ranging from actual failures on demand to potential failures attributable to various causes, including environmental qualification, seismic qualification, human error, design or installation errors, etc. Many SSFFs and RCIC functional failures ~~do~~may not involve actual failures of equipment.

Because the contribution to risk of the structures and systems included in ~~the SSFF~~this performance indicator varies considerably, and because potential as well as actual failures are included, it is not possible to assign a risk-significance to this indicator. It is intended to be used as a possible precursor to more important equipment problems, until an indicator of safety system performance more directly related to risk can be developed.

Clarifying Notes

Reporting of Safety System Functional Failures

The definition of SSFFs is identical to the wording of the current revision to 10 CFR 50.73(a)(2)(v). Because of overlap among various reporting requirements in 10 CFR 50.73, some events or conditions that result in safety system functional failures may be properly reported in accordance with other paragraphs of 10 CFR 50.73, particularly paragraphs (a)(2)(i), (a)(2)(ii), and (a)(2)(vii). An event or condition that meets the requirements for reporting under another paragraph of 10 CFR 50.73 should be evaluated to determine if it also prevented the fulfillment of a safety function. Should this be the case, the requirements of paragraph (a)(2)(v) are also met and the event or condition should be included in the quarterly performance indicator report as an SSFF. The level of judgement for reporting an event or condition under paragraph (a)(2)(v) as an SSFF is a reasonable expectation of preventing the fulfillment of a safety function.

In the past, LERs may not have explicitly identified whether an event or condition was reportable under 10 CFR 50.73(a)(2)(v) (i.e., all pertinent boxes may not have been checked). It is important to ensure that the applicability of 10 CFR 50.73(a)(2)(v) has been explicitly considered for each LER considered for this performance indicator.

NUREG-1022: Unless otherwise specified in this guideline, guidance contained in the latest revision to NUREG-1022, "Event Reporting Guidelines, 10CFR 50.72 and 50.73," that is applicable to reporting under 10 CFR 50.73(a)(2)(v), should be used to assess the reportability of safety system functional failures for this performance indicator.

Planned Evolution for maintenance or surveillance testing: NUREG-1022, Revision 2, page 56 states, "The following types of events or conditions generally are not reportable under these criteria:...Removal of a system or part of a system from service as part of a planned evolution for maintenance or surveillance testing..."

The word "planned" is defined as follows:

"Planned" means the activity is undertaken voluntarily, at the licensee's discretion, and is not required to restore operability or for continued plant operation.

A single event or condition that affects several systems: counts as only one failure.

Multiple occurrences of a system failure: the number of failures to be counted depends upon whether the system was declared operable between occurrences. If the licensee knew that the problem existed, tried to correct it, and considered the system to be operable, but the system was subsequently found to have been inoperable the entire time, multiple failures will be counted whether or not they are reported in the same LER. But if the licensee knew that a potential problem existed and declared the system inoperable, subsequent failures of the system for the same problem would not be counted as long as the system was not declared operable in the interim. Similarly, in situations where the licensee did not realize that a problem existed (and thus could not have intentionally declared the system inoperable or corrected the problem), only one failure is counted.

Additional failures: a failure leading to an evaluation in which additional failures are found is only counted as one failure; new problems found during the evaluation are not counted, even if the causes or failure modes are different. The intent is to not count additional events when problems are discovered while resolving the original problem.

Engineering analyses: events in which the licensee declared a system inoperable but an engineering analysis later determined that the system was capable of performing its safety function are not counted, even if the system was removed from service to perform the analysis.

Reporting date of SSFF: the date of the SSFF is the Report Date of the LER.

Reporting of RCIC Functional Failures For Plants That Do Not Report RCIC SSFFs

In addition to the general guidance provided above, the following guidance is provided for plants that do not report RCIC function failures as SSFFs.

While safety systems are generally thought of as those that are designed to mitigate design basis accidents, both safety and non-safety related equipment and systems have been considered for this performance indicator due to their risk importance. Therefore, although RCIC may be considered as a non-safety related, non-mitigation system in some license and design bases, RCIC functional failures are included in the reporting of this performance indicator due to their risk importance.

The definition of a RCIC functional failure is any event or condition that prevented, or could have prevented the total loss of its decay heat removal function. For purposes of this performance indicator, in determining the need to report an event or condition, the following criteria apply:

- The RCIC system must operate long enough to complete its decay heat removal function.

- Engineering Analyses: events in which the licensee declared RCIC unable to perform its decay heat removal function but an engineering analysis later determined that RCIC was capable of performing the specified function are not counted, even if the system was removed from service to perform the analysis. Reasonable engineering judgement should be applied in determining whether a condition or event prevented, or could have prevented the fulfillment of its decay heat removal function.

- In determining the need to report an event or condition that affects the RCIC decay heat removal function, it is not necessary to assume an additional random single failure in the RCIC system, however, it is necessary to consider other existing plant conditions.

- Events may include one or more personnel errors, including procedure violations; equipment failures; inadequate maintenance; or design, analysis, fabrication, equipment qualification, construction, or procedural deficiencies.

- Individual component failures need not be reported if redundant equipment in the RCIC system was available to perform the RCIC decay heat removal function.

- This decay heat removal function can be achieved through either automatic or manual means.

Reporting date of RCIC functional failure: No later than 60 days from date of event or discovery to be consistent with SSFF reporting. The performance indicator reporting date for plants that use the reporting regulation, the date of the RCIC functional failure is the report date of the LER.

Stephen D. Floyd
SENIOR DIRECTOR
REGULATORY REFORM

February 23, 2001

Mr. Michael T. Lesar
Acting Chief, Rules and Directives Branch
Division of Administrative Services
Office of Administration
Mail Stop: T-6 D59
U.S. Nuclear Regulatory Commission
Washington DC 20555-0001

SUBJECT: Public Comment on the First Year of Initial Implementation of the Reactor Oversight Process (ROP)

Dear Mr. Lesar:

On behalf of the nuclear energy industry, the Nuclear Energy Institute (NEI) is submitting the enclosed list of ROP key issues that we believe should be considered for discussion during a public workshop on First Year Lessons Learned, scheduled for March 26-28, 2001. The Nuclear Regulatory Commission requested a list of key issues to be discussed at the workshop in the *Federal Register* on December 14, 2000 (65 *Fed. Reg.* 78215).

We appreciate NRC's approach throughout the development and first year of implementation of the new ROP. The continuing degree of public interaction and cooperation exhibited by all stakeholders has allowed the process to effectively address most emerging questions and unforeseen concerns in a timely and fair manner. Without forsaking its responsibility to make the final decision, NRC has been willing to openly share its ideas and to allow public comment on a real-time basis. The result has been a far better product than could have been achieved in the past. This new paradigm of communication and understanding between the regulator, licensees and the non-industry public is to be commended. It should also be emulated for future regulatory improvement initiatives.

The issues provided in the enclosure reflect information accumulated during an industry workshop conducted in January of this year, as well as individual suggestions provided by NEI member companies.

Attachment 8

The industry looks forward to a continuing dialogue with the NRC and other stakeholders during and following the planned public workshop. Following the workshop, we shall be providing detailed comments on the first year of the ROP, as requested in the aforecited *Federal Register* Notice.

Sincerely,

Stephen D. Floyd

Enclosure

Proposed Reactor Oversight Process Key Issues for NRC Lessons Learned Workshop

Inspection Process Improvements –

- Discussion of criteria, definition and threshold for no-color findings
- Discuss potential to pilot use of plant self-assessment in place of NRC inspection (including baseline)
- Discussion of value-added from inspections conducted to date (i.e., have certain inspections revealed no or little risk significant results? Should their frequency be reduced or be replaced by plant self-assessment?)
- Need for review of scope and frequency of inspections (e.g., engineering, PI&R, radiation protection)
- Discussion of the safety conscious work environment portion of the PI&R inspection module (specifically any guidance as to when this portion of the module is to be implemented and criteria that might be used in classifying issues/findings in this area)
- Discuss information sharing pre-exit, at exit and in inspection reports
- Resources dedicated to baseline inspection: Will there be a learning curve and an expected decrease in inspection hours (which many licensees feel is higher than the previous core inspection program)?
- Scope, status and implementation experiences with MD 8.3 (specifically the use of conditional core damage probability and limitations on resident inspector interface with licensees)

SDP Process Improvements

- Lessons Learned from containment and shutdown SDPs (Others to be discussed in other breakout sessions on RP, Physical Protection, Fire Protection)
- Discussion of expectations for information sharing of PRA/SDP analysis during inspections, prior to inspection report and prior to regulatory conferences
- Has the appropriate amount of risk analysis been performed? Too much for the issues at hand?
- SDP process timeliness and communications, particularly when generic application issues arise
- Discuss method to capture lessons learned on SDPs, particularly FAQs regarding SDPs (process and issue specific)
- Discuss Group 1, 2 and 3 thresholds

Assessment –

- Lessons Learned, comments from NRC and industry: Are there process efficiencies to be gained?
- Discussion of graded reset for inspection findings (after NRC acceptance of root cause and corrective action plans)
- Cross-NRC Region oversight challenges (i.e., licensees with sites in multiple regions)

Attachment 8 continued

- Discuss semi-annual and annual assessment process
- Discuss experience with Action Matrix

Unavailability Definition – The mitigating system unavailability PIs have received by far the greatest number of Frequently Asked Questions and deserve a separate breakout session. Among issues which should be discussed are:

- Basic definition differences exist between Maintenance Rule, PRA/PSA, WANO/INPO, and NEI 99-02
- fault exposure
- credit for operator action;
- differences between TS operability and unavailability
- thresholds
- support systems impact on front-line system unavailability
- impact on effective preventive maintenance vs. crossing threshold
- unintended consequences of avoiding unavailability

Unplanned power changes –

- Discussion of NRC and industry concerns regarding interpretation of the current indicator and the NRC proposed replacement.
- Discussion of power reductions conducted to accommodate economic considerations

Identification and disposition of "Cross-Cutting Issues" –

- Need for criteria, thresholds and definitions (for example, what makes an issue truly cross-cutting? What is a "cross-cutting" human performance issue? A "cross-cutting" procedure issue?)
- Discussion of revision to MC 0610* Oct 6 to clarify cross-cutting issue reporting
- Inconsistency across regions
- CAP inspection: What have been results? Lessons learned? What is NRC expectation for the use of "risk analysis" in the CAP program? Use of SDP in CAP program?

PI data reporting expectations— What are NRC expectations for PI data quality, administration, and de minimus unavailability? Discussion of inspector ratcheting or suggestions to upgrade PI program compared to another site

Fire Protection Issues –

- Inspection module and scope
- revision of SDP
- transparency of SDP use to inspected licensees
- treatment of licensing basis (including SERs and previous inspection results)
- guidelines for issue resolution between licensees and regions
- streamlining time spent on findings consistent with risk significance

Enforcement Policy –

- What level of attention will be applied to PI verification given the end of the grace period for reporting errors?
- To what extent is NRC management directing inspectors to focus on risk significant issues and not on de minimus reporting errors?
- Does the submittal of an FAQ protect a licensee from enforcement action (except willful, etc.) since it represents a valid technical question as to reporting requirements?
- What enforcement discretion time period will be given as new PIs are added (learning curve period)?

Physical Protection Cornerstone

- Implications of recent Commission SRM
- SDP – need relative quick action on replacement; findings should reflect safety consequences; needs to be able to handle routine items (e.g., loss of control of weapon)
- Inspections are compliance oriented rather than risk informed and performance based
- Overlap of PA security equipment index with inspection of IDS and CCTV. Consider elimination of inspection (or extend inspection frequency to every 3 years since PI covers the area
- Need concurrent completion of various items: Safeguards Performance Assessment (replacement for OSRE); rewrite of security rules (10 CFR 73.55); stabilize adversary characteristics;

Radiation Safety

- Discussion of recent ALARA inspection results, including violations and SDP approach
- Improving focus of baseline inspections – inspection effort appears unchanged or greater; consider less frequent inspections
- Public Radiation SDP – transportation (improve risk basis for waste classification); rad material control (clarify finding criteria – final monitoring point and number of occurrences; two year time frame for aggregating rad material control findings)
- Occupational Rad Safety SDP -- Exposure control application variability from inspector to inspector
- Applicability of the SDP to discrete radioactive particles

Emergency Preparedness

- Regional understanding and buy-in of process
- Application of no color findings
- Inspection reports do not explain how finding significance (color) arrived at.
- Discussion of how supplemental inspection findings are assessed for risk significance (how are findings colored? Discuss examples in EP)

- Impact on station staff of PI inspection and Biennial exercise in the same week
- Communicator definition
- Lack of NRC/licensees understanding of the Action Matrix

Risk-Based PIs – This area is still in the early Phase 1 review stage; however, it might be appropriate to gather input from this large assembly of NRC and industry potential users of the RBPIs. Discuss process for consideration; candidate PIs; discuss potential data collection and interpretation issues/problems

ROP LESSONS LEARNED
STATEMENT OF ISSUES
UNAVAILABILITY PI

NOTE: The Nuclear Energy Institute (NEI) formed a working group that established an industry proposal on the issues related to the Safety System Unavailability (SSU) PI. The NRC Focus Group met and developed its proposed position. A joint meeting of the two groups was convened, and the results are presented in the Proposed Resolution to each issue.

ISSUE NO. 1: What unavailable hours should be included in the SSU PI?

a. Should all unavailable hours of a train be counted whenever the function is required, or only when the train is required?

b. Should on-line maintenance be excluded from the SSU if the licensee has a risk analysis that shows the increase in risk is small?

c. Should support system unavailable hours be counted as monitored system unavailable hours?

d. Should unavailable hours due to design deficiencies be excluded from the SSU PI?

BACKGROUND:

a. The SSU PI was derived from the WANO Safety System Performance Indicator (SSPI). The WANO SSPI (and consequently the ROP SSU) does not include unavailable hours that occur when a train is not required to be operable by Tech Specs, even though the function may be required. For example, in cold shutdown, refueling or defueled, only one train of emergency ac power is required. Any maintenance, including overhaul, on another train is not included in the SSU calculation for that train. Should all unavailable hours of a train be counted whenever the function is required, or only when the train is required?

b. There was a perceived unfairness in counting unavailable hours for licensees that perform on-line maintenance in accordance with a risk-informed tech spec change that extended the AOT for that purpose, because off-line maintenance is not counted and the risk is comparable. Should on-line maintenance be excluded form the SSU if the licensee has a risk analysis that show the increase in risk is small?

c. The WANO SSPI includes unavailable hours for a monitored system when support system unavailability (except emergency ac power) renders the monitored system unavailable. Should such support system unavailable hours be counted as monitored system unavailable hours? If so, what requirements would be placed on the support system to assess unavailability of the monitored system, e.g., must the support system be single failure proof and/or meet all design basis requirements?

d. Design deficiencies can manifest themselves years later. The time of failure would normally be known and could result large fault exposure hours that could result in a non-green PI for up to three years. To avoid such a situation, the ROP excludes design deficiencies from the PI calculation. Should unavailable hours due to design deficiencies be excluded from the SSU PI?

PROPOSED RESOLUTION:

a. The NRC Focus Group and the NEI/Industry working group agree that the correct way to measure unavailability during power operation is to count unavailable hours when any train in a system is out of service and the system function is required. There is also agreement that, while shutdown, the licensee's shutdown risk-management plan would

Attachment 9

identify those safety functions and methods necessary to manage the increase in risk that may result from shutdown activities. The NRC Focus Group would count unavailable hours for any method for performing a safety function that is credited in that plan. The NEI/Industry working group proposes to only count unavailability of the primary and/or the first backup methods of performing a safety function. Both groups agree that unavailable hours during power operation and while shutdown should be tracked separately, and eventually there should be separate indicators for the two phases of operation. However, until shutdown indicators are developed, it is acceptable to combine both power operation and shutdown unavailability in one indicator.

b. Both NRC and NEI agree that unavailable hours should be counted for on-line maintenance (and off-line maintenance whenever two trains of any system whose function is required by T.S. are not available).

c. The NRC and NEI agree that, as long as support systems are not monitored in the SSU, support system unavailable hours should be cascaded to the monitored systems. We also agree that the support system is available if a single train of that system is available (i.e., support systems are not required to be single-failure proof).

d. Both NRC and NEI agree that long-standing design deficiencies should not be included in the SSU, and that consideration should be given to identifying long-standing design deficiencies as those that occur before the 12 month period of the current calculation.

CANDIDATE FOR EXTERNAL LESSONS LEARNED WORKSHOP:

[X] Yes, as is   [ ] Yes, after completing additional work (briefly identify additional work needed)   [ ] No

FINAL NRC RECOMMENDED APPROACH:

ROP LESSONS LEARNED
STATEMENT OF ISSUES
UNAVAILABILITY PI

ISSUE NO. 2: How should demand and run failures be handled in the SSU?

a. Is a reliability indicator necessary, or can the SSU alone provide meaningful indication of safety system performance?

b. Should estimates of fault exposure hours be used in lieu of an unreliability indicator? Are there acceptable alternatives?

c. Should the ROP include a provision to allow licensees to remove large increments of fault exposure hours after one year if the NRC has approved the licensee's corrective actions?

BACKGROUND:

The WANO SSPI does not use an unreliability indicator. Instead, WANO incorporates unreliability into the SSU through the use of fault exposure hours (FEHs) associated with a train failure (although not explicitly stated, the failure should include run failures as well as demand failures). If the time of discovery of the failure is known but the time of failure is not known, the fault exposure time is taken as one-half the time (t/2) since the last successful test or operation of the train. The problem is that the t/2 estimate will usually dominate the unavailable hours. Should estimates of fault exposure hours be used in lieu of an unreliability indicator? Are there acceptable alternatives to the use of estimated FEHs, such as using a baseline inspection to assess the risk of demand and run failures? Or should an unreliability indicator be developed for use prior to the completion of the RBPI effort? If an unreliability indicator is used, how are FEHs then used for discovered conditions, such as a closed manual valve in the injection path of a monitored system?

A large increment of fault exposure hours, such as might occur due to a failed surveillance test of 30 days or longer interval, could result in a non-green PI for up to three years. This creates two concerns. First, any additional problems in that train could be masked, since the white band is from one to three times the width of the green band, so that another threshold might not be crossed to trigger additional NRC engagement. Second, after some period of time, the PI is no longer indicative of current performance. For these reasons, a provision has been added to the ROP SSU to allow licensees to remove large (≥336 hours) increments of FEHs due to a single event or condition after one year if the problem has been corrected and the NRC Region has approved the resolution. Should the ROP include a provision to allow licensees to remove large increments of fault exposure hours after one year if the NRC has approved the licensee's corrective actions?

PROPOSED RESOLUTION:

a. The working groups agree that an unreliability indicator is the correct way to measure demand and load-run failures. However, in the absence of unreliability indicators, the groups agree that FEHs due to demand and load-run failures can introduce large blocks of unavailable hours into the SSU that can misrepresent the risk at the plant and can limit the NRC's ability to respond to performance issues.

b. The NRC and NEI groups agree that the best resolution to the question of FEHs due to demand and load-run failures is to remove them from the SSU and to use the Significance Determination Process to assess those events.

c. The NRC and NEI agree that removal of FEHs due to demand and load-run failures from the SSU will greatly reduce the problem, and that, for large increments of FEHs due to other causes, this provision is acceptable.

CANDIDATE FOR EXTERNAL LESSONS LEARNED WORKSHOP: [Task lead makes a recommendation; final decision will be made at the internal lessons learned workshop]

[X] Yes, as is   [ ] Yes, after completing additional work (briefly identify additional work needed)   [ ] No

FINAL NRC RECOMMENDED APPROACH:

ROP LESSONS LEARNED
STATEMENT OF ISSUES
UNAVAILABILITY PI

ISSUE NO. 3: What credit should be allowed for operator recovery actions?

BACKGROUND: The SSU allows credit for operator actions to restore a train when a demand is received during surveillance testing if the actions are virtually certain to be successful. The same criterion can be used to allow credit for recovery from an operator error or a malfunction. Licensees have requested credit for operator actions to recover from uncomplicated maintenance configurations, and from more complicated maintenance or test configurations when there is sufficient time until the train is required by the accident analysis. Probabilistic Safety Analyses include probabilities of operator recovery actions as important components in the progression of any accident scenario. In the ROP, credit has been limited because the SSU PI measures equipment performance, not operator performance. If the recovery actions are virtually certain to be successful, then the probability is near 1 and credit can be given. Anything short of 'virtually certain' requires estimation of a number less than 1, which is likely dependent upon the situation, the crew, and perhaps the specific operator involved. Therefore no credit is given. Maintenance activities conducted during chaotic conditions in the course of an analyzed accident are not considered to be virtually certain. Should the SSU allow credit for operator actions that are virtually certain to be successful? Should there be credit allowed for more complicated recovery actions? If so, what conditions should be applied to such actions?

PROPOSED RESOLUTION: Both NRC and NEI agree that the current allowances for operator recovery action should be retained with no changes or additions, but that plant-specific exceptions could be made for special circumstances.

CANDIDATE FOR EXTERNAL LESSONS LEARNED WORKSHOP: [Task lead makes a recommendation; final decision will be made at the internal lessons learned workshop]

[X] Yes, as is [ ] Yes, after completing additional work (briefly identify additional work needed) [ ] No

FINAL NRC RECOMMENDED APPROACH:

ROP LESSONS LEARNED
STATEMENT OF ISSUES
UNAVAILABILITY PI

ISSUE NO. 4: Should default values for hours train required be allowed?

BACKGROUND: The calculation of the SSU uses, as the denominator in the calculation of train unavailability, the hours the train was required during the most recent 12 quarters. The WANO guidance has allowed licensees to estimate this number through the use of default hours to reduce the data collection burden on licensees. In some cases, the default value is non-conservative in that the denominator would be larger than the actual required hours. This will cause the calculated value to be lower than the true value. In the case of the EDG SSU, the error could be as much as 60 percent. Should the ROP allow licensees to use the non-conservative default hours approved by WANO? If not, is there an acceptable alternative estimate?

PROPOSED RESOLUTION: NEI proposes to allow the use of default values for the hours a train is required because of the burden on licensees to collect the actual information. The NRC has data that show the calculated SSU value can be significantly underestimated, in certain circumstances, when the default hours are used. The NRC will look at the possibility of providing guidelines for licensees on when the use of default hours is acceptable and when it is not.

CANDIDATE FOR EXTERNAL LESSONS LEARNED WORKSHOP: [Task lead makes a recommendation; final decision will be made at the internal lessons learned workshop]

[X] Yes, as is   [ ] Yes, after completing additional work (briefly identify additional work needed)   [ ] No

FINAL NRC RECOMMENDED APPROACH:

FAQ LOG 11				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
11.16	PP01	**Question** For Security Intrusion Detection Systems (IDS), if the number of IDS false alarms exceeds "x" number per hour, the licensee considers the IDS segment failed and implements compensatory measures for the IDS segment. There are two questions: 1) If an IDS segment is declared failed (but left in service) and security personnel's inspection identifies no reason to contact the maintenance organization for resolution and operability testing of the IDS segment by security personnel is successful (without performing corrective maintenance) should compensatory hours be counted for the time period that the IDS was considered as failed? 2) If an IDS segment is declared failed (but left in service) and security personnel contact the maintenance organization for resolution, the maintenance evaluation does not disclose any malfunction, and operability testing of the IDS segment by security personnel is successful, should compensatory hours be counted for the time period that the IDS was considered as failed?	7/12/00 Discussed. On hold for review. 8/3/00 NEI proposed response. 8/29 NEI response revision. 9/21 – Discussed. On hold. 10/27 ComEd revision of FAQ and proposed response. 10/31 – Discussed. NRC to review proposed revision. 12/6 – Discussed. HOLD for discussion on 1/10/01 1/10/01 – Discussed. On hold. NRC to discuss with region III. **2/8/01 – NEI response revision. Tentative Approval** <u>3/2/01 – Approved. Post April 1, 2001.</u>	ComEd

Attachment 10

FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: 1. Yes. If the false alarms exceed the station security program limit, then the compensatory hours are counted regardless of which personnel evaluate the condition; provided it is in accordance with the station security program. In the absence of guidance in the security program, qualified individuals can disposition the condition. 2. Yes. See answer to 1.		

FAQ Log 15

Temp No.	PI	Question/Response	Status	Plant/ Co.
15.8	MS01	**Question:** The Emergency AC Power System monitored function for the indicator is, "The ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power." However, on page 26 of NEI 99-02, Rev 0 under testing where simple operator action is allowed for restoration, it states "The intent of this paragraph is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions." For purposes of this indicator are we to assume a simultaneous loss of off-site power and also accident conditions? This may make a difference on the diesel generator response, operator restoration actions and ultimately whether or not we count unavailability during our surveillance test runs. **Response:** Yes, you should assume a simultaneous loss of off-site power and also accident conditions if they are specified in your design and licensing bases.	Introduced 10/31 12/5 NEI Response added 1/10/2001 – Discussed. Hold. W. Warren to contact VY. 2/5/01 – Alternate response provided by NEI **2/8/01 – Response revised. Use alternate resposne. Tentative Approval as revised.** 3/2/01 – Approved. Post 3/2/01.	VY
15.12	MS01 MS02 MS03 MS04	**Question:** 1. Should support system unavailability be counted in the monitored safety system unavailability PI if analysis or engineering judgement has determined that the support system can be restored to available status such that the monitored system remains available to perform its intended safety function? 2. Do the criteria for determining availability described in NEI 99-02, Revision 0, page 26 lines 31-40 apply to this situation?	Introduced 10/31 12/5/00 – NEI, Licensee proposed response added. 3/2/01 – Discussed. FAQ to be discussed as part of SSU focus group.	ComEd

FAQ Log 15

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Licensee Proposed Response: 1. No. During both testing and non-testing situations, the criteria described in NEI 99-02, Revision 0, page 33, lines 7-9 should apply, "In these cases, analysis or sound engineering judgment may be used to determine the effect of support system unavailability on the monitored system." If the analysis or engineering judgment determines that the unavailability of the support system does not impair the ability of the monitored system to perform its intended safety function, then the support system unavailability should not be counted in the monitored system PI. For example, if engineering analysis determines that the unavailability of a ventilation support system for the emergency diesel generator does not adversely impact the availability of the emergency diesel generator to perform its intended function, the unavailability of the support system would not be counted in the emergency diesel generator PI. The engineering analysis must evaluate such things as; the length of time between an event and the time the ventilation system is required to be available to support the safety function of the emergency diesel generator, the complexity the actions required by plant operators to restore the availability of the ventilation system, and the probability of success for the restoration actions. Restoration actions should be contained in a written procedure and must not require diagnosis or repair. The engineering analysis must provide a high degree of assurance that the unavailability of the ventilation support system does not impact the ability of the emergency diesel generator to perform its safety function. This treatment is consistent with maintenance rule and PRA. 2. No. In NEI 99-02, Revision 0, page 26, lines 31-40, criteria for exclusion of planned unavailability for testing activities of monitored systems are described. The criteria established in this section describe required actions or barriers which must be in place during *testing* so that unavailability of the monitored system is not counted in the monitored system PI.		

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.1	IE01	**Question:** Following a forced outage during which work was performed on a reactor coolant pump motor to reduce vibration, the unit was restarted. It should be noted the forced outage was not the result of the reactor coolant pump problem; the unit tripped for other reasons. During the unit restart while increasing power, an annunciator came in indicating excessive vibration on the reactor coolant pump in question. The annunciator response procedure directed the unit operator to an emergency shutdown procedure. The emergency shutdown procedure then instructed the unit operator to rapidly shut down the unit, however this particular procedure accomplishes rapid shut down without a reactor trip in that it directs the power level to be brought down to a nominal value prior to instructing the reactor trip breaker to be opened. This shutdown sequence is consistent with normal shutdown procedures. Would this be considered an unplanned SCRAM or an unplanned power change? **Response:** It would count as an unplanned power change.	Introduced 12/6 3/2/01 – Discussed. TVA to provide information on EOP language.	TVA
16.2	MS03	**Question:** The Nuclear Service Water (NSW) system provides assured suction supply to the Auxiliary Feedwater (AFW) system under certain accident scenarios. During a postulated seismic event concurrent with a loss of offsite power (LOOP), the normal non-safety related, non-seismic condensate suction sources are assumed to be unavailable. Flow testing is performed under the plant's Generic Letter 89-13 program to assure adequate flow. The alignment used in this testing renders this flowpath unavailable to fulfill its assured supply function. However, the normal condensate source remains available. Recently a reactor trip occurred during the performance of this testing. The testing was terminated, but due to resource limitations during event recovery, the normal operating alignment was not restored. Therefore, the assured AFW supply remained unavailable for an extended period. However, during the event, the AFW system started automatically on a valid autostart signal (2/4 lo-lo SG level in 1/4 SGs, loss of both main feedwater pumps) and continued to operate for a period of two days to maintain steam generator levels drawing suction from the normal condensate supply. Previously, whenever the assured supply has been unavailable, whether for testing or other alignments, the entire AFW system has been deemed unavailable based on a hypothetical design basis event scenario. However, the real world event described above results in the dichotomy of calling a system unavailable because its assured supply is unavailable while it was in fact fulfilling its design basis function. Under the NEI 99-02 guidelines, how should unavailability be addressed in conditions where the assured supply is unavailable with the normal supply available? **Response:** The purpose of the safety system unavailability indictor is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents. Since the assumed suction supply to the AFW system is credited for off-normal events or accidents, the unavailable time should be counted unless the system could have been promptly restored by a dedicated operator stationed for that purpose during the testing	Introduced 12/6 2/5/01 – Response added by NEI. **3/2/01 – Tentative Approval.**	Catawba

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.3	MS01 MS02 MS03 MS04	**Question:** Concerning removal of fault unavailable hours NEI 99-02 states: "Fault exposure hours associated with a single item may be removed after 4 quarters have elapsed from discovery…" In the case we are considering, the hours were discovered in the third calendar quarter. When do the four elapsed quarters begin? At the start of the fourth calendar quarter? and end at the conclusion of next year's third quarter? If the period of calculation of the indicator value was only four calendar quarters beginning the quarter after they occurred, and the fault unavailable hours are reported in the quarter in which they occurred, what's the point in removing them after they are no longer a factor in the calculation of the indicator? "Fault exposure hours are removed by submitting a change report that provides a revision to the reported hours for the affected quarter(s). The change report should include a comment to document this action." **Response:** The fault exposure hours should be reported for third quarter data and may be removed with the submittal of the next year's third quarter data provided the criteria for removing fault exposure hours are met. All safety system unavailability performance indicators calculate train unavailability for 12 quarters. Therefore, the situation you describe would not exist.	Introduced 12/6 2/5/01 – NEI response added. <u>3/2/01 –</u> **<u>Tentative Approval.</u>**	IP2
16.4	BI01	**Question:** NRC Performance Indicator BI-01 monitors the integrity of the fuel cladding. We are required to report the maximum monthly RCS activity in micro-Curies per gram dose equivalent Iodine-131 and express it as a percentage of the technical specification limit. FAQ 226 asks if licensees with limits more restrictive than the technical specification limit should use the more restrictive limit or the TS limit. The FAQ answer states that the licensee should use the most restrictive regulatory limit unless it is "insufficient to assure plant safety." If administrative controls are imposed "... to ensure that TS limits are met and to ensure the public health and safety, that limit should be used for this PI." Vermont Yankee has a Basis for Maintaining Operation (BMO) that is in effect that limits the Reactor Coolant System to 0.05 uCi/gm I-131 dose equivalent. This BMO, 98-36, entitled "Effect of Main steam Tunnel and Turbine Building HELBs on the HVAC Rooms," is concerned with Control Room habitability and the regulatory dose limits to the operators. It states that there is no concern with increased radiological dose to the public from the VY HELB off-site dose analyses in FSAR Section 14.6. FAQ 226 mentions the concern for both assuring plant safety and public health and safety as the intent for the more restrictive administrative controls that may be in effect. NRC Administrative Letter 98-10, which is mentioned in the answer to this FAQ, states in the Discussion that the concern is the safe operation of the facility. Our question is this: "Is Vermont Yankee required to use the lower administrative limit imposed by the BMO (0.05 uCi/gm I-131 dose equivalent) even though public health and safety is not compromised if this limit is exceeded?" **Response:** No. The intent is when administrative limits are required to ensure 10 CFR Part 100 limits are not exceeded.	Introduced 12/6 2/5/01 – NEI response added. <u>3/2/01 –</u> **<u>Tentative Approval.</u>**	VY

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.5	MS03	**Question:** **Appendix D** NEI 99-02 states (p 26) that Planned Unavailable Hours include "…testing, unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose." Also,(p 40) The control room operator must be "…an operator independent of other control room operator immediate actions that may also be required. Therefore, an individual must be 'dedicated.'" Ginna Station's Standby Aux Feedwater Pumps do not have an auto-start signal; they are required to be manually started by an operator (not a "dedicated" operator) within 10 minutes. Should this be counted as unavailable time? **Licensee Proposed Response:** Ginna Station should be allowed to use their Tech Spec requirements (manually started within 10 minutes) as guidance for counting Planned Unavailable Hours for the SDAFW pumps during testing, i.e. if the Standby Aux Feedwater Pumps are available by Tech Spec, the PI should not count them as not available.	Introduced 12/6 Discussed. Need to confirm compliance with NUREG 0737	Ginna
16.6	MS01 MS02 MS03 MS04	**Question:** NOTE: This is similar to FAQ Log 15, Temp No. 15.4 NEI 99-02 states (p 26) "Restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair. Credit for a dedicated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur." Ginna Station Results and Test personnel are qualified to perform valve lineups and are in the control room and/or stationed locally during testing. Do the R&T personnel with the written test procedure meet the guidance of NEI 99-02 for being able to restore equipment to service when needed and thus not counting the testing time as planned unavailable hours? **Licensee Proposed Response:** Yes, provided the plant personnel are qualified and designated to perform the restoration function and are not performing any restoration steps for which they are not qualified. ~~this meets the NEI 99-02 guidance for not counting the testing as planned unavailable hours.~~ Ginna Station considers the restoration steps of the test procedures to be the "written procedure" for the required "restoration actions". The qualified R&T personnel (rather than a dedicated operator) with the test procedures allow Ginna Station to take credit for restoration actions that are virtually certain to be successful during accident conditions while performing tests and thus this time should not count towards Planned Unavailable Hours.	Introduced 12/6 Discussed. Need more information on qualification of R&T tech and actions required **3/2/01 – Response revision. Tentative Approval as revised.**	Ginna
16.10	MS01	**Question:** Turkey Point's Unit 3 Emergency Diesel Generators EDGs) are air-cooled, using very large radiators (eight assemblies, each weighing 300-400 pounds) which form one end of the EDG building. After 12 years of operation the radiators began to exhibit signs of leakage, and the plant decided to replace them. Replacing all eight radiator assemblies is a labor-intensive activity, that requires that sections of the missile shield grating be removed, heat deflecting cowling be cut away, and support structures be built above and around the existing radiators to facilitate the fitup process. This activity could not have been completed within the standard 72 hour allowed outage time (AOT). Last year Turkey Point requested, and received, a license amendment for an extended AOT, specifically for the replacement of these radiators. NEI 99-02 allows for the exclusion of planned overhaul maintenance hours from the EAC performance indicator, but does not define overhaul maintenance. Does an activity as extensive as replacing the majority of the cooling system, for which an extended AOT was granted, qualify as overhaul maintenance? **Licensee Proposed Response:** In this specific case, yes, for three reasons: (1) that activity involves disassembly and reassembly of major portions of the EDG system en toto, tantamount to an overhaul; (2) the activity is infrequent, i.e., the same as the vendor's recommendation for overhaul of the engine alone (every 12 years); and (3) the NRC specifically granted an AOT extension for this activity supported by a quantitative analysis	Introduced 12/6 2/08/01 – Response revised. Tentative Approval as revised. **3/2/01 – Approved. Post 3/2/01.**	Turkey Point

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.11	MS02 MS04	**Question:** At our ocean plant we periodically recirculate the water in our intake structure causing the temperature to rise in order to control marine growth. This process is carried out over a six hour period in which the temperature is raised slowly in order to chase fish toward the fish elevator so they can be removed from the intake and thus minimize the consequential fish kill. Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with warm water in the intake is less than half of the evolution. A dedicated operator is stationed for the evolution, and by procedure at any point, can back out and restore normal intake temperatures by pushing a single button to reposition a single circulating water gate. The gate is large and may take several minutes to reposition and clear the intake of the warm water, but a single button with a dedicated operator, in close communication with the control room initiates the gate closure. During this evolution, one train of service water, a support system for HPSI and RHR, is aligned to the opposite unit intake and remains fully Operable in accordance with the Technical Specifications. The second train is aligned to participate in the heat treat, and while functional, has water beyond the temperature required to perform its design function. This design function of the support system is restored with normal intake temperatures by the dedicated operator realigning the gate with a single button if needed. Gate operation is tested before the start of the evolution and restoration actions are virtually certain. The ability of the safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. Does the time required to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR? **Licensee Proposed Response:** No. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. There are no unavailable hours.	Introduced 12/6 12/6 Discussed. HOLD needs more clarity in the question 2/5/01 – need to know design basis	San Onofre
16.13	MS04	**Question:** **Appendix D** NEI 99-02 Revision 0 requires the Residual Heat Removal (RHR) system to satisfy two separate functions: • The ability to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS • The ability of the RHR system to remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance These functions are completed by the Emergency Core Cooling System on most Westinghouse PWR designs. South Texas Project has a unique design for these functions completed by two separate systems with a shared common heat exchanger. How should unavailability be counted for South Texas Project?.~~Since South Texas Project has a unique design for the systems that satisfy the RHR function of the performance indicator, how should unavailability hours be counted for those systems?~~	Introduced 12/6 12/6 Discussed. HOLD needs detailed discussion w/ STP 1/8/01 NEI response revision. 3/1/01 – Sentence added to response. STP request for review completion. **3/2/01 – Tentative Approval as revised.**	South Texas

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<tr><th colspan="5">FAQ Log 16</th></tr>
<tr><th>Temp No.</th><th>PI</th><th>Question/Response</th><th>Status</th><th>Plant/ Co.</th></tr>
<tr><td></td><td></td><td>Response:
~~NEI 99-02 Revision 0 requires the Residual Heat Removal (RHR) system to satisfy two separate functions:~~
~~- The ability to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS~~
~~- The ability of the RHR system to remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance~~
~~These functions are completed by the Emergency Core Cooling System on most Westinghouse PWR designs. South Texas Project has a unique design for these functions completed by two separate systems with a shared common heat exchanger.~~

Due to the unique design South Texas project, unavailability will be determined as follows: ~~has interpreted the requirements of NEI 99-02 and is applying that interpretation as follows:~~

• In plant Modes 1, 2, 3, and 4 South Texas Project will count the unavailability of the Low Head Safety Injection Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS". The RHR pump does not contribute to the performance of this safety function since it can not take suction on the containment sump.
• In plant Modes 4, 5, and 6 South Texas Project will count the unavailability hours of the RHR Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance". The RHR loop is required to be isolated from the Reactor Coolant System in Modes 1, 2, and 3 due to the system design. This requirement prevents the system from performing its intended cooling function until plant pressure and temperature are lowered to a value consistent with the system design.

Overlap times when both functions/systems are required will be adjusted to eliminate double counting the same time periods.

This position is consistent with the direction published in Frequently Asked Question #149.</td><td></td><td></td></tr>
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FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.14	MS03	**Question:** **Appendix D Question** Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate from the two trains of turbine-driven auxiliary feedwater pumps. The piping for the MDFP (when in the auxiliary feedwater mode) is separate from the auxiliary feedwater system up to the steam generator containment isolation valves. The MDFP is not part of the original plant design, as it was added in 1985 following our loss-of-feedwater event to provide "a diverse means of supplying auxiliary feedwater to the steam generators, thus improving the reliability and availability of the auxiliary feedwater system" (quote from the DB Updated Safety Analysis Report). The resolution to FAQ 182 was that Palo Verde should count the unavailability hours for their startup feedwater pump. However, since the DB MDFP (like the Palo Verde startup feedwater pump) is manually initiated, DB has not been reporting unavailability hours for the MDFP due to the exception stated on page 69 of NEI 99-02 Revision 0. The DB MDFP is non-safety related, non-seismic, and is not Class 1E powered or automatically connected to the emergency diesel generators. Based upon discussions with Palo Verde, their startup feedwater pump is Class 1E powered and automatically connected to an EDG. The DB MDFP is required by the Technical Specifications to be operable in modes 1 - 3. However, the Tech Specs do not require the MDFP to be aligned in the auxiliary feedwater mode when below 40 percent power. (The MDFP is used in the main feedwater mode as a startup feedwater pump when less than 40% power). The DB auxiliary feedwater system is designed to automatically feed only an intact steam generator in the event of a steam or feedwater line break. Manual action must be taken to isolate the MDFP from a faulted steam generator. The MDFP is included in the plant PRA, and is classified as high risk-significant for Davis-Besse Per the DB Tech Specs, the MDFP and both trains of turbine-driven auxiliary feedwater pumps are required in Modes 1-3. The MDFP does not fit the NEI definition of either an "installed spare" or a "redundant extra train" per NEI 99-02, Rev. 0, pages 30 - 31. Should the Davis-Besse MDFP be reported as a third train of Auxiliary Feedwater, even though it is manually initiated? (Note: this FAQ is similar to FAQs 205 and 206 submitted by Crystal River regarding the auxiliary feedwater system) **Response:**	Introduced 12/6	Davis-Besse

FAQ Log 17

Temp No.	PI	Question/Response	Status	Plant/ Co.
17.2	PP01	**Question:** For sites that do not use CCTV for primary assessment of the perimeter IDS, how is the Indicator Value for the Protected Area Security Equipment Performance Index calculated? **NRC Response:** For sites that do not use CCTV for primary assessment, as stated in their approved security plan, use only the IDS Unavailability index for the Indicator Value. The Indicator value will be the IDS Unavailability Index divided by one for sites where these conditions exist. The exclusion of the CCTV index from the performance indicator calculation should be indicated by reporting a CCTV normalization factor of zero and zero CCTV compensatory hours for each affected unit. **Alternate Response** Option 1 No change. Option 2 For sites that do not use CCTV for primary assessment, as stated in their approved security plan, use only a weighted IDS Unavailability index for the Indicator Value. The Indicator value will be the IDS Unavailability Index divided by 3/2 for sites where the conditions exist. Option 3 For those sites, the PI will be treated as a unique design. The sites should continue to report compensatory hours and normalization factor, but no indicator value will be calculated.	Introduced 1/10 **1/10/2001 – Tentative Approval – NRC action to confirm acceptability with C. See 2/7/01 – NEI proposed alternate responses.** 3/2/01 – Discussed.	NRC

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.1	MS01 MS02 MS03 MS04	**Question:** Should surveillance testing of the safety system auto actuation system (e.g. Solid State Protection System testing, Engineered Safety Feature testing, Logic System Functional Testing) be considered as unavailable time for all the affected safety systems? During certain surveillance testing an entire train of safety systems may have the automatic feature inhibited.	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern
18.2	MS01 MS02 MS03 MS04	**Question:** When reporting safety system unavailable time there are periodic (such as weekly) evolutions that although they may not be simple actions to restore a safety system, they result in the safety system being unavailable for no more than several minutes. Is this level of tracking unavailable time required?	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern
18.3	MS04	**Question:** If a plant is allowed by its Tech Specs, to secure an operating Shut Down Cooling (SDC) train and not enter a LCO action statement, are they required to incur SDC train unavailability for the purposes of the RHR indicator, when the SDC train is taken out of service? **Licensee Proposed Response:** No. A SDC train "is required" as specified in the plant's Tech. Specs. If the plant is not in a SDC LCO action statement, then no SDC (RHR) unavailability is incurred.	Introduced 2/8 Methodology for CE plants RHR needs to be reviewed Discussed. 3/2/01 – NEI action to obtain additional information	Calvert Cliffs
18.4	MS04	**Question:** With our unit shutdown, in Mode 6 with water level in the refuel pool greater than 23 feet above the top of the fuel assemblies seated in the reactor vessel, only one SDC loop is required to be operable and in operation by our Tech. Specs. While in this plant condition, may the operable SDC loop be replaced with an alternate NRC approved means of decay heat removal without incurring SDC (RHR) unavailability?	Introduced 2/8 Methodology for CE plants RHR needs to be reviewed Discussed. 3/2/01 – NEI action to obtain additional information	Calvert Cliffs

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.5	IE02	**Question:** Should the reactor trip described in the scenario below be included as a "Scram with Loss of Normal Heat Removal?" A very heavy rainfall caused the turbine building gutters to overflow and water entered the interior of the turbine building. Water subsequently leaked onto the main feedwater pump B area and affected the pump speed control circuitry. Feedwater pump B speed increased and feedwater pump A speed decreased to compensate. Shortly thereafter feedwater pump B speed decreased and feedwater pump A increased. The control room operators placed the feedwater pump turbine master speed controller in manual in an attempt to recover from the transient. This action stabilized pump speed. The transient caused the digital feedwater control system to place the feedwater regulating valves in manual control. Levels in steam generators B, C, and D began to rise. A hi-hi steam generator level (P-14) occurred in steam generator B. The P-14 signal tripped both main feedwater pumps, generated a feedwater isolation signal, and tripped the main turbine. The reactor tripped upon turbine trip. Main feedwater pumps tripped on the P-14 signal as part of the plant design. Feedwater pump B had malfunctioned; however, feedwater pump A remained available. Auxiliary feedwater system automatic starts occurred for motor driven pumps A and B as well as the turbine driven auxiliary feedwater pump (all of these responses were as designed). **Response:** No, because the MFW system was readily restorable to perform its post trip cooldown function	Introduced 2/8 3/2/01 – **Tentative Approval**	Catawba
18.6	IE03	**Question:** An unscheduled power reduction was commenced to clean main condensed water boxes. This decision was a result of indications of condenser fouling. Concurrent with this condition was the plant entry into Abnormal Operating Procedure "High Winds, Hurricanes, and Tornadoes" due to sustained winds of > 60 MPH. This resulted in rough Lake Ontario conditions. The lake agitation created high levels of suspended crud (silt) which was drawn into the Circ. Water System (evidenced by Condenser fouling indications). In response to the safety concerns arising from the external events, and minimize the impact of these events on plant operational conditions, a power reduction was taken to clean and restore normal condenser operation. Actual power change was not predictable 72 hours in advance. The anticipatory power reduction was intended to reduce the impact of external events (high winds creating unsettled lake conditions resulting in silt intrusion) on plant operational conditions. Should this downpower be included as a unplanned power change? **Response:**	Introduced 2/8 Need more information	FitzPatrick
18.7	MS01 MS02 MS03 MS04	**Question:** ~~The Mitigating Systems Performance Indicators allow for operator action to restore a system without incurring a penalty while performing system tests. Can the same criteria be applied to Safety System Unavailability in non-test circumstances if the affected system(s) can be promptly restored either by an operator in the control room or qualified plant personnel remote from the control room; provided there is a means of communication with the Control Room?~~ **Response** ~~No. The mitigating system PI only allows for operator action for simple actions when the system is in test and must not require diagnosis or repair.~~	**Introduced 2/8/01. Discussed. Tentative Approval.** **3/2/01 – Withdrawn.**	Prairie Island

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.1	IE03	**Question:** If a plant chooses to correct a deficiency less than 72 hours following discovery (a steam leak or other condition) and reduces plant power to limit radiation exposure (ALARA) and this reduction in power (>20%) is not required by the license bases would this reduction be counted? **Response:**	Introduced 3/1	River Bend
19.2	MS01 MS02 MS03 MS04	**Question:** Page 4 of NEI 99-02 states: "The guidance provided in Revision 0 to NEI 99-02 is to be applied on a forward fit basis…", however there is also a provision to reset fault exposure hours (page 29) that requires 4 quarters have elapsed since discovery. If reset of fault exposure is applied to historical data submitted under the "best effort" collection method (i.e. grandfathered data previously collected under INPO 98-005 guidelines), does this constitute a backfit of the NEI 99-02 guidance? Additionally, if the reset of fault exposure hours does constitute a backfit, would the station then be required to revise all of the historical data to conform with all 99-02 requirements? **Response:**	Introduced 3/1	Susquehanna
19.3	MS04	**Question:** **(Potential Appendix D question – Question being reworded)** Analysis has shown that when RHR is operated in the Suppression Pool Cooling (SPC) Mode, the potential for a waterhammer in the RHR piping exists for design basis accident conditions of LOCA with simultaneous LOOP. SPC is used during normal plant operation to control suppression pool temperature within Tech Spec requirements, and for quarterly Tech Spec surveillance testing. We do not enter an LCO when SPC mode is used for routine suppression pool temperature control or surveillance testing because the frequency of operation is minimal, and total run time is limited under administrative controls. If the specified design basis accident scenario occurs while the RHR system is in SPC mode, there is a potential for collateral equipment damage that could subsequently affect the ability of the system to perform the safety function. If the time RHR is run in SPC mode must be counted as unavailability, then our station RHR system indicator will be forever white due to the number of hours of normal SPC run time (approximately 300 hours per year). This would tend to mask any other problems, which would not be visible until the indicator turned yellow at 5.0%. Should our station count unavailability for the time when RHR is operated in SPC mode for temperature control or surveillance testing? **Response:**	Introduced 3/1	Susquehanna

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.4	IE03	**Question:** The hydrogen cooler for the main generator began leaking at an increased rate above normal IP-3 historical trends but well within limits requiring a shutdown and with limited potential with that rate to cause gas binding in the hydrogen cooler heat exchanger that could result in a high delta temperature trip of the generator. For the degraded condition which has been seen in the past and repaired, an action plan was developed, work packages prepared, materials procured, a monitoring program established and an administrative limit established at which a decision would be taken to correct the condition including heat exchanger replacement. Approximately December 15, 2000, there was a step increase in the hydrogen leak rate although still below the administrative limit but approaching it. Because of the upcoming holidays, management decided adequate resources may not be available if the leak were to increase further so it was decided to shut the plant down and replace the hydrogen cooler heat exchangers. This decision and the subsequent necessary actions was less than the 72 hour criteria of the guidance in NEI-99-02 (12/15 - 12/18). IP-3's concluded based on the NEI-99-02 guidance for PI IE03, specifically at FAQ # 6 that the event and IP-3's preparation met that criterion so the shutdown was not counted Does this event count? **Response:**	Introduced 3/1	IP3

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.5	MS01	**Question:** NEI 99-02, Revision 0, page 48, line 1 (Clarifying Notes) states: "When determining fault exposure hours for the failure of an EDG to load-run following a successful start, the last successful operation or test is the previous successful load-run (not just a successful start). To be considered a successful load-run operation or test, an EDG load-run attempt must have followed a successful start and satisfied one of the following criteria: - a load run of any duration that resulted from a real (e.g.. not a test) manual or automatic start signal - a load-run test that successfully satisfied the plant's load and duration test specifications - other operation (e.g., special tests) in which the emergency diesel generator was run for at least one hour with at least 50% of design load When an EDG fails to satisfy the 12/18/24- month 24-hour duration surveillance test, the faulted hours are computed based on the last known satisfactory load test of the diesel generator as defined in the three bullets above." This may be in conflict, however, with the following sentence, which states: "For example, if the EDG is shutdown during a surveillance test because of a failure that would prevent the EDG from satisfying the surveillance criteria, the fault exposure unavailable hours would be computed based upon the time of the last surveillance test that would have exposed the discovered fault." If a 24-hour duration surveillance test revealed a failure due to a cause that pre-existed during the entire 12/18/24 month operating cycle, then it is not clear whether fault exposure should be calculated based on the guidance in the three listed criteria, or the three listed criteria are totally disregarded if the failure was not revealed until the 24-hour duration surveillance test. This is particularly unclear for a condition that could have been revealed during any test (e.g., any monthly 1-hour load-run surveillance), but actually happened during the 24-hour duration surveillance test. **Licensee Proposed Response:** The three listed criteria are correct and appropriate for determining fault exposure unavailable hours. The 24-hour duration surveillance test is a performance test. There is no regulatory basis (unless discussed in an individual plant's FSAR) that an EDG be capable of functioning for 24 continuous hours. Nor is there any risk informed basis that an EDG must be capable of functioning for 24 continuous hours, as a loss of an offsite electric power system would probably be restored within the one-hour period (82% probability for Palo Verde during power operation) discussed in the three listed criteria and EDGs are typically redundant equipment.	Introduced 3/1 3/2/01 – Discussed. NEI action to revise to clarify question and proposed resonse.	APSC

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.6	MS01 MS02 MS03 MS04	**Question:** **(Potential Appendix D Question)** At Prairie Island the three safeguards Cooling Water (service water) pumps, two for operation (one is a swing pump), were declared inoperable for lack of qualified source of lineshaft bearing water. There were two sources of water to the lineshaft bearings: a non-safeguards well water supply (preferred, because it supplied cleaner water) and the Filtered Water supply off the cooling Water system (standby source, starts automatically on low pressure). The Filtered Water system was originally designated as safety-related but had been downgraded in 1977 and subsequent modifications did not maintain the original quality level. Also, the original design and installation of the Filtered Water system failed to provide safety related electrical power for the Filtered Water strainer backwash system. During a Loss Of Offsite Power (LOOP), this could have resulted in clogging of the Filtered Water strainers and subsequent loss of Filtered Water to the lineshaft bearings, making the cooling water pumps inoperable. The plant declared all three safeguards Cooling Water pumps inoperable and entered into Technical Specifications 3.0.c (motherhood). Compensatory measures were implemented to ensure continued availability of water to the lineshaft bearings. The plant requested a Notification of Enforcement Discretion (NOED) that allowed continued operation of both units until installation of a temporary modification to provide qualified Filtered Water supply to two of the three pumps was completed (14 days). Two initiating events were identified that could result in the loss of bearing water and unavailability of the cooling water pumps (seismic and LOOP) were discussed during the NOED request. The plant concluded that the risk of continued operation during the 14 day NOED period (compared to the risk of a two unit shutdown – where Cooling water would still have been required for decay heat removal) was low; based on the low likelihood of risk-significant initiating events, the equipment remained available to protect the decay heat removal safety function had an event occurred, the compensatory measures put in place, and the limited time over which the condition existed. The NRC accepted this safety rationale, combined with the compensatory actions as an adequate basis, and granted the NOED. The Cooling Water System is a support system and it's unavailability affects: High Pressure Safety Injection, Auxiliary Feedwater, Residual Heat Removal, and Unit 1 Emergency AC (Unit 2 Emergency AC is cooled independent of Cooling Water). Prairie Island included the time that the Cooling Water Pumps were declared inoperable, approximately 300 hours, as unplanned unavailability. This resulted in two White Indicators (one on each unit). Two other systems (one per unit) are on the Green/White threshold, and two others (again, one per unit) are Green, but close to the Green/White threshold. Depending on the number of unavailable hours in future quarters, and since these indicators are 12 quarter averages, the indicators on or near the threshold may change from Green to White and back again. Should the time from implementation of compensatory measures to completion of the temporary modification be counted as safety system unavailability? **Response:** •	Introduced 3/1	Prairie Island
19.7	PP01	**Question:** **Proposed Replacement for FAQ 250** If a new Intrusion Detection System (IDS) or Closed Circuit Television (CCTV) design change package has been prepared by Engineering and funding for the new upgrade has been approved by management but the physical installation will not occur immediately, when does the NEI 99-02 "Scheduled equipment upgrade" exemption occur to stop counting the compensatory hours?	Introduced 3/2 **3/2/01 -- Approved. Post 3/2/01.**	

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: In the situation where system degradation results in a condition that cannot be corrected under the normal maintenance program (e.g., engineering evaluation specified the need for a system/component modification or upgrade), and the system requires compensatory posting, the compensatory hours stop being counted toward the PI for those conditions addressed within the scope of the modification after such an evaluation has been made and the station has formally initiated a commitment in writing with descriptive information about the upgrade plan including scope of the project, anticipated schedule, and expected expenditures. This formally initiated upgrade is the result of established work practices to design fund, procure, install and test the project. A note should be made in the comment section of the PI submittal that the compensatory hours are being excluded under this provision. Compensatory hour counting resumes when the upgrade is complete and operating as intended by site requirements for sign-off. Reasonableness should be applied with respect to a justifiable length of time the compensatory hours are excluded from the PI.		